Realistic calculation of wind generation capacity credits

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***Abstract*—The concept of capacity credit measures the ability of generation to support demand in power systems. This is of particular importance for wind generation, whose available capacity depends primarily on physical resource availability as opposed to mechanical availability; as a result, and differently from conventional generation, it is possible for the total available output of a system's wind generation to be very close to zero. This paper reviews different methods for calculating capacity credits, and discusses the important considerations for a realistic calculation with reference to a new Great Britain study. The key conclusion is that the correct methodology for a capacity credit calculation is closely tied to the intended application; as a consequence, there can no one universal preferred approach for all applications.**

***Index Terms*—Wind power generation, Power system reliability, Power system modeling**

I. Introduction

The installed capacity of wind generation is increasing worldwide. For instance, in Great Britain installed wind capacity has increased from 678 M in 2003 to 2083 MW in 2007 [1], and may exceed 20 GW by 2030 [2]. This has significant implications for the ability of the electric power system to secure peak demand. The availability of conventional generating capacity is largely a mechanical matter; hence, to a good approximation individual unit availabilities are independent, and there is in practice no chance of having near-zero capacity available.

The system-wide available wind capacity, however, depends primarily on resource availability (i.e. how windy it is). As a result, it is possible when there is little wind anywhere on a system for the available capacity to be very near zero. This is a particular concern in winter-peaking systems, where the highest demand is driven by low temperatures; very low temperatures are often due to a high pressure area which generates little wind. There is evidence that this issue may indeed be realised in the Great Britain system [3].

The concept of capacity credit is widely used to quantify the ability of wind generation to support demand (a report from an International Energy Agency collaboration [4] provides a survey of recent studies.) The capacity credit of additional generation in a system is defined either via the additional demand which it can support on the system without increasing system risk, or alternatively by comparison with the load-carrying ability of conventional plant.

This paper surveys the important considerations for a realistic capacity credit calculation, using the Great Britain system for illustration. Section II defines capacity credit and the relevant simulated risk indices, and introduces the Great Britain context. Section III then derives the demand and generation models used in this study. Results for the capacity credit of wind in the Great Britain System are then presented in Section IV, and Section V uses this as a basis for discussion of broader issues in capacity credit calculations. Finally, Section VI answers the question implied by the title of this paper, i.e. 'how does one perform a realistic capacity credit calculation?'

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II. Risk Calculations and Capacity Credits

A. Definitions of Capacity Credit

The concept of the capacity credit, or capacity value, of additional generation to a system is not new. It has become much more prominent given the increasing importance of variable-output renewable generation, but has been in use for many decades in the context of thermal and hydro generation (see for example Garver [5].)

The definition of capacity credit is independent of the risk index used. There are various different definitions in the literature; one of the most common, used here and by other authors, is *Effective Load Carrying Capability* (ELCC) [5]–[7]. The ELCC of additional generation in a system is calculated in a series of steps:

1) Calculate the value I_0 of the risk index before the additional generation is introduced.
2) Introduce the additional generation to the risk calculation.
3) The ELCC of the additional generation is the additional demand which returns the risk index to its original value I_0.

The other major class of definition of capacity credit involves comparison with the load-supporting ability of conventional plant [8]–[10]. A major disadvantage of this approach, when compared to that considering additional load, is that the result of the calculation depends on the properties of the reference conventional unit considered. [8] states that a reference unit should not be perfectly reliable, as real generating units are not perfectly reliable. There is in fact no reason why the reference conventional unit should not have perfect reliability, as this makes no implication as to the properties of real units on the system. Moreover, as it is easy to agree on the properties of a perfect unit, this would make comparison between different studies more straightforward. It must also be remembered that removing a perfect conventional unit is not directly equivalent to increasing load; a perfect unit has the same output at all times, whereas additional load will have an annual variation roughly in proportion to the existing load.

[8] also states that prior to the capacity credit calculation the ELCC should be scaled so that the risk index matches a target value. This is justified on the basis that many utilities plan their systems around a target risk level. Such a process of adjusting system parameters prior to performing a calculation seems unusual. It is more conventional to perform any calculation with the actual system parameters, and it is widely accepted in the literature that the correct usage of simulated risk indices is to compare relative values from different calculations, rather than stating absolute values (see for example [11].) However, one concern when using the actual demand levels is that the capacity credit then depends on demand; in a sense, this just reflects reality, but some users might prefer to regard capacity credit as being a system property independent of the precise demand level.

It is certainly the case that when comparing capacity credit results from different studies, it is necessary to take account of differences in the methodology used, whether in the definition of capacity credit, or in the associated risk index.

B. Risk indices

1) Loss of Load Probability: Loss Of Load Probability (LOLP) is the probability of available generating capacity being insufficient to support demand at a given time.

2) Loss of Load Expectation: This is the risk index most commonly used worldwide in the calculation of capacity credits for wind generation. If I_t^{LOLP} is the LOLP in time period (e.g. hour) t, then the Loss Of Load Expectation (LOLE) is the expected (in the mathematical sense) number of periods in a given time span T for which available generation is insufficient to meet demand:

$$I^{LOLE} = \sum_{t \in T} I_t^{LOLP}. \tag{1}$$

LOLE is often expressed in days per 10 years, for which a typical target value is 1 day in 10 years. It is important to remember than LOLE values calculated using different duration of the time periods $\{t\}$ are not directly comparable; for instance, if the time unit is 1 hour then an outage of 3 hours at peak would be recorded as 3 hours, whereas if the time unit is one day the same outage would effectively be recorded as having 24 hours' duration.

3) Loss of Energy Expectation: Loss Of Energy Expectation (LOLE), or alternatively Expected Energy Not Supplied (EENS) is the expected amount of demand not met in a given time span. Unlike LOLE, it considers the severity of power shortages as well as their existence. However, it is less commonly used in capacity credit calculations.

4) Planning Versus Operational Timescales: On an operational (or 'next-season') timescale, the main uncertainty in demand is due to weather variability. On a planning timescale, however, there are additional uncertainties due to underlying long-term demand trends. If modelled in the risk calculation, this additional uncertainty will have an effect on the calculated capacity credit value.

C. The Great Britain Context

Generation adequacy calculations in Great Britain have usually considered the ability to meet winter peak demand. This dates back to the nationalised industry when the Central Electricity Generating Board (CEGB), which ran the transmission system in England and Wales, was required to plan its generation to a standard of failing to meet peak demand in 3 winters out of 100 [12]. The Electricity Council, which set the planning standard, in 1986

> ENDORSED the proposal that new coal-fired stations should only be justified for capacity reasons against the needs of a 24 per cent planning margin, thus accepting the lower standard of security implied thereby, namely the 9 per cent risk standard.

The precise context of this change is not entirely clear from the relevant minutes [13]; it is certainly the case that the intention behind the decision was not a simple reduction of the risk as experienced by customers. In any case, risk standards for the England and Wales system considered in isolation cannot be translated directly into standards for the present unified Great Britain system, due to the excess of generating capacity in Scotland.

This risk standard was in practice defined with respect to a specific risk calculation, involving particular assumptions about generation and demand [12]. The mean winter weekday generating plant availability was assumed to be 85%, with variations modelled as a Normal distribution with standard deviation (SD) 3.75%. The uncertainty in demand due to weather alone was modelled by an SD of 3.87%, and the uncertainty in demand forecast on a planning timescale was modelled by an SD of 9%. In addition, the 3% (or 9%) risk standards actually referred to the probability of meeting 92.5% of demand (it was assumed that 7.5% could be shed by voltage and frequency reductions.)

In the modern liberalised market, there is no direct equivalent to this generation planning standard; the capital spending decisions of generating companies are motivated by anticipation of profits from future power sales. The nearest indirect equivalents do however still work in terms of winter peak:

- The Transmission System Operator's Winter Outlook report [14] looks at the adequacy of generation to support winter peak demand. The calculation is performed in terms of deterministic scenarios, where different classes of generation are assigned 'assumed availabilities' (e.g. 85% for coal). In order to quantify wind's contribution to securing demand in the same way, an assumed availability (a form of capacity credit) is required.
- The Great Britain Security and Quality of Supply Standard [15] contains the GB transmission network planning

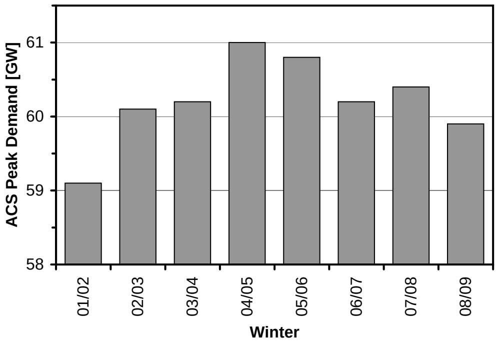

Fig. 1. GB ACS peak demand figures since 2001. The figure for 2008/9 is the forecast figure from autumn 08; the out-turn is predicted to be almost 2 GW lower than this forecast [16].

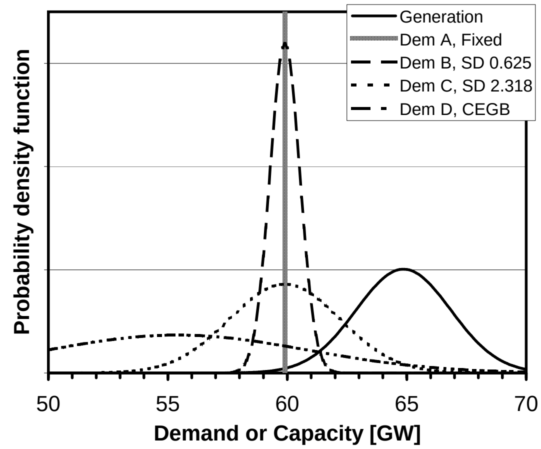

Fig. 2. Probability density functions for available conventional generation capacity, and also the various demand distributions. Demand case A is a fixed demand of 59.9 GW.

standards. The required transmission transfer capacities are defined in terms of weather-corrected winter peak flows. In calculating the required transfers, the generation on the system is reduced to an 20% plant margin (the plant at the low end of the economic merit order is excluded.) With a significant proportion of wind on the system, it must be assigned an appropriate capacity credit in order to achieve an *effective* 20% margin. Wind, having near zero marginal cost, is high-merit; however, because of its different availability properties, 1 MW of wind cannot be regarded as equivalent to 1 MW of conventional generation in this calculation.

For these applications, defined at time of winter peak, it is clearly preferable to use a capacity credit based on a winter peak risk calculation. This applies even if some aspects, particularly the treatment of wind generation, are less straightforward in such a winter peak capacity credit calculation.

III. Great Britain Test System

A. Demand

Peak demand in the GB system is usually described by two figures for weather-corrected demand:

- *Average Cold Spell (ACS) peak demand.* The annual peak demand which 'has a 50% chance of being exceeded as a result of weather variation alone' (pp. 28-29 of [15]).
- *1 in 20 peak demand.* The peak demand which has a 1 in 20 chance of being exceeded.

Both these statistics vary from year to year, depending on underlying demand growth or reduction. A demand forecast for the winter ahead is published in the early autumn by National Grid in the Winter Outlook [14]; an 'ACS peak demand out-turn' figure is then calculated once the winter is over (the figures since 2001 are plotted in Fig. 1.) The out-turn is usually similar to the forecast. However, for 2008/9, the out-turn is anticipated to be almost 2 GW below the prediction of 59.9 GW; this is due to a combination of consumer response to high prices and the economic downturn [16]. It must be noted that these figures are for demand as seen by the transmission network; within these figures, distribution-connected generation is treated as negative demand. The growth of such distributed generation may be the cause of some of the long-term decrease in underlying transmission system demand levels.

Four demand models will be used in this paper:

A. Fixed demand equal to the 2008/9 ACS forecast figure of 59.9 GW.
B. ACS peak demand is Normally distributed with mean 59.9 GW and standard deviation (SD) 0.625 GW. This SD is based on the 1 in 20 demand for winter 08/09 of 60.9 GW, and the fact that the upper 95% critical value of a Normal distribution is 1.6 SDs above the mean.
C. ACS peak demand is Normally distributed with mean 59.9 GW and SD 2.318 GW. This is taken from the estimate used by the CEGB in its generation planning, that the variability of demand due to weather alone may be represented by an SD equal to 3.87% of the mean demand.
D. System adequacy defined in terms of ability to meet 92.5% of winter peak demand, assuming that peak demand is Normally distributed with mean 59.9 GW and SD $59.9 \times \sqrt{0.0387^2 + 0.09^2} = 5.868$ GW. This comes from the CEGB planning model, where additional uncertainty in demand on a planning timescale is represented by an additional 9% SD. The distribution for 92.5% of peak demand is then Normal with mean 55.408 and SD 5.428.

These distributions are plotted in Fig. 2.

B. Conventional Generation

The supply model used is based on the generating units considered in the 2008/9 Winter Outlook; these are summarised in Table I. The 'assumed availabilities' from the Winter Outlook are interpreted as unit availability probabilities. This work assumes that unit availabilities are independent, and caps the available capacity from each generating station at the station's realisable capability (this may be lower than the sum of unit capacities, because of e.g. transmission or pollution constraints.) Hence, given a list of which units are available, the procedure for calculating the total available capacity would be

TABLE I
CONVENTIONAL UNIT TYPES ON THE GB TRANSMISSION SYSTEM, THE SUMS OF STATION CAPACITIES FOR EACH TYPE, AND THE ASSUMED AVAILABILITIES FROM THE WINTER OUTLOOK [14].

Type	Capacity (GW)	Availability
Nuclear	10.2	80%
Interconnector	2.0	100%
Hydro	1.1	60%
Coal	27.8	85%
Oil	3.5	95%
Pump storage	2.7	95%
OCGT	1.5	95%
CCGT	25.2	90%
	74.0	

- For each station, add the capacities of the available units
  - If the sum of available units' capacities is less than or equal to the station realisable capacity, the station available capacity is the sum of available unit capacities.
  - If the sum of available unit capacities is greater than the station realisable capacity, the station available capacity is the station capacity.
- The system available capacity is then the sum of the station available capacities.

For example, if a station has two 600 MW units, both of which are available, and the station realisable capacity is 1200 MW, then the station available capacity would be 1200 MW. If on the other hand, due to limited transmission capacity, the station realisable capacity was 1100 MW, then the station available capacity would be 1100 MW.

The resulting probability distribution for available conventional generating capacity is plotted, alongside the various demand models used, in Fig. 2. The distribution has mean 64.86 GW and standard deviation 1.98 GW.

C. GB Metered Wind Data

The volume of real wind output data available in Great Britain is very limited. This is partly due to a significant penetration of wind generation having been achieved only recently (the installed capacity passed 1 GW in 2005 and 2 GW in 2007, see Table 7.4 of [1]), and partly due to availability time series from individual wind farms being regarded as commercially sensitive. National Grid, in its role as Transmission System Operator, has published aggregated data on the relationship between available wind load factor of transmission metered wind and demand [14] (see Table II).

D. Simulated Wind Time Series

A simulated GB national wind load factor hourly time series has been developed at the University of Edinburgh [17]. The methodology is related to that in [18], but with the inclusion of geographical weighting based on the location of current and planned wind farm locations.

The model takes hourly wind speed measurements from the UK Meteorological (Met) Office weather stations, and

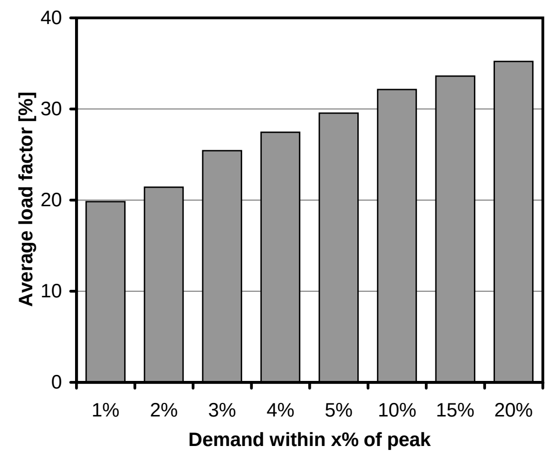

Fig. 3. Simulated GB load factors from hours of demand within x% of winter peak, for the years 2001-2007. Simulated wind output time series taken from [17].

converts them into hourly regional load factors, and finally a GB average. The Met Office provides hourly wind speed measurements at 10m height, averaged over 10 minutes measured from minute 40 to minute 50 of the hour [19]. The time series run from 2001-2007 inclusive.

The GB load factor time series is obtained through the following steps:

1) Filter Met Office wind speeds to remove duplicated or corrupt measurements
2) Extrapolate wind speeds from 10m to 60m [20]
3) Transform to load factors using the standard Bonus 2 MW wind turbine power curve [21]
4) Calculate hourly regional average load factors
5) Calculate hourly GB load factor by geographically weighted average of regional load factors, based on the aggregated wind capacity in operation, construction, or planning in each region [22]

In addition, the individual simulated wind farm load factors are calibrated, so that the GB long term load factor matches that observed historically [1].

E. Wind model at winter peak

Discussion of year-round or whole-winter risk calculations will appear in Section V-C; the discussion here relates only to annual peak risk calculations as required for some Great Britain applications.

The available data on any quantity at time of winter peak is limited, as by definition the annual peak occurs just once a year. It may reasonably be assumed that the statistical properties of conventional generating capacity remain very similar throughout the winter, which allows the use of further data. However, the wind resource at winter peak may be substantially poorer than that at times when demand is slightly below peak; this is demonstrated in Fig. 3, which shows simulated load factors at hours with demand within 1%, 2%, 3%, 4%, 5%, 10%, 15% and 20% of annual peak. As a compromise between having a reasonably substantial amount of data and that data being relevant to the specific time of

TABLE II
COINCIDENCE OF GB DEMAND AND METERED OUTPUT OF TRANSMISSION-CONNECTED WIND OVER APPROXIMATELY 1.5 YEARS. FOR INSTANCE, THE TOP LEFT ENTRY (430) IS THE NUMBER OF HOURS WHERE DEMAND WAS BETWEEN 40 AND 50% OF PEAK, AND WIND AVAILABILITY WAS BETWEEN 0 AND 10% OF RATED CAPACITY. DATA FROM [14].

% of peak	Wind load factor (%)										Total	Mean
Demand	0-	10-	20-	30-	40-	50-	60-	70-	80-	90-	hours	Load Factor
40-50	430	225	145	86	54	29	27	16	4	0	1016	19.2
50-60	628	396	252	174	172	128	106	85	34	0	1975	26.5
60-70	699	469	325	258	206	170	132	122	62	3	2446	28.5
70-80	626	412	304	211	160	168	127	115	50	3	2176	28.6
80-90	188	166	142	92	79	89	80	73	42	3	954	34.8
90-100	39	31	26	24	14	10	10	10	3	1	168	30.2
Total	2610	1699	1194	845	685	594	482	421	195	10	8735	27.7

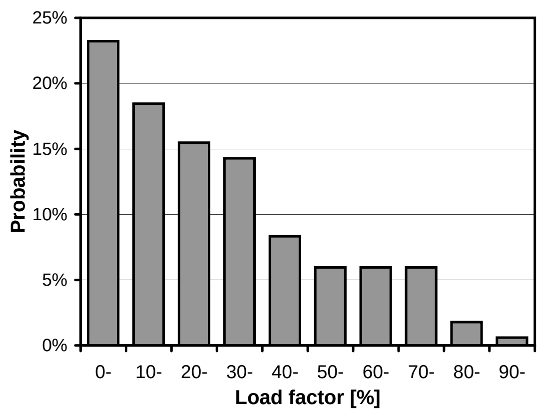

Fig. 4. Probability mass function for available load factor from GB wind generation, based on the metered data in Table II. If the load factor falls in a particular range, it is deemed to be at the middle of that range (i.e. load factors in the range 0-10% are deemed to be 5%.) The mean of the load factor distribution is 0.302, and the SD is 0.229.

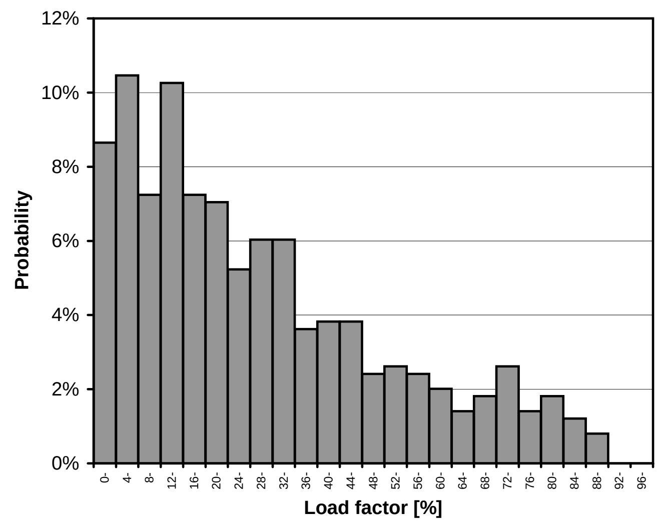

Fig. 5. Probability mass function for available load factor from GB wind generation, based on the Edinburgh simulated data. The mean of the load factor distribution is 0.295, and the SD is 0.230.

winter peak, the probability distributions used for winter peak wind availability are based on histograms of the number of hours of demand within a certain percentage of that season's peak:

- *GB metered data*: hours within 10% of peak (168 hours over 1.5 years). Probability distribution plotted in Fig. 4.
- *Edinburgh simulated data*: hours within 5% of peak (503 hours over 7 years). Probability distribution plotted in Fig. 5.

Both these distributions will be used in the calculations which follow. The differences between the two time series arise (in addition to issues of simulated versus metered data) from the different time spans of the simulated and meterd data, and the concentration of transmission-metered wind farms in Scotland.

F. Risk Calculation with Wind Generation

1) LOLP calculation: The winter peak LOLP in a system with wind generation is:

$$I^{LOLP} = \sum_i p(W = w_i) p(X < 0 | W = w_i). \qquad (2)$$

W is the available wind capacity; as described above, for the two wind models considered here this is a discrete random variable. X is the excess of available generating capacity over demand; for each wind scenario, the probability that conventional generating capacity can meet the residual demand (after subtraction of available wind capacity) must be evaluated.

2) Additional reserve requirement: It is generally accepted that significant penetrations of wind generation require additional operating reserve to ensure a secure operating state. At present, the total GB response and reserve requirement at time of winter peak is 3600 MW, made up of 400 MW of response and 3200 MW of reserve [16]. The reserve requirement for wind generation in isolation is estimated to be 1/3 of *available* wind capacity (note: available, not installed) [16]. The total reserve requirement for the system with wind generation available is then

$$R^{\mathrm{tot}}(w) = 400 + \sqrt{3200^2 + (w/3)^2}, \qquad (3)$$

where w is the wind capacity. The reserve requirements are added as 'square root of sum of squares', as the derivation is risk-based. The application of this formula will be discussed further in the next (Results) section.

3) Risk of eroding reserve margins: Capacity credit calculations have been performed based on the risk of reserve

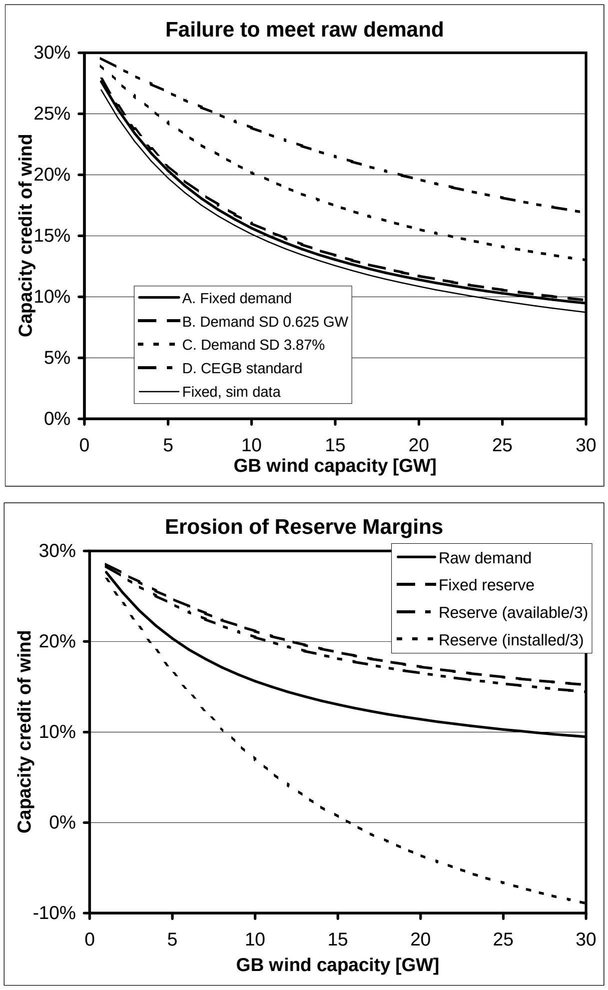

Fig. 6. Capacity credit results for the GB test system. Upper panel: LOLP in terms of meeting raw demand. Lower panel: risk of reserve margin erosion ('installed' and 'available' refer to the definition of w in (3). All calculations performed using the wind model based on National Grid data; in the upper panel, the fixed demand case is also plotted using the Edinburgh simulated wind model.

margins being eroded, as well as in terms of failure to meet raw demand. This is achieved simply by redefining the excess of generating capacity over demand as [available capacity] - [demand] - [reserve requirement].

IV. Results

The capacity credit results for the GB test system are plotted in Fig. 6. As in other studies, the capacity credit decreases as the installed wind capacity is increased. In addition, the result that the capacity credit increases as demand uncertainty (and hence risk) increase is intuitively reasonable, as additional generation should be more valuable when risk is higher. This will be discussed further in the next section.

More interesting is the effect of defining adequacy in terms of maintaining reserve margin rather than meeting raw demand, lower panel of Fig. 6. If a fixed reserve requirement is applied (evaluating (3) with $w = 0$) then, as in the previous paragraph, risk and capacity credit increase together. Expression (3), with w taken to be the *installed* capacity, is regarded by National Grid as a credible worst case requirement [16]; the capacity credit then goes negative when the addition reserve requirement becomes comparable with the load factor. Results are also plotted with w taken to be the *available* wind capacity. In this latter case the capacity credit barely decreases below the fixed-demand result, as even at high penetrations the available wind capacity is rarely close to rated. A true reserve requirement, taking into account wind forecasting, will lie between these two extreme results.

V. Discussion

A. Capacity Credit of Conventional Generation in Normal Approximation

This explanation closely follows the method of [6]. The Normal approximation is reasonable for the GB system as long as LOLP is greater than about 1%, but it may be less useful on smaller systems.

Suppose that the surplus of available generation over demand in a system is currently Normally distributed with mean μ and variance σ^2 (this variance may include uncertainty in both demand and generator availability.) A new conventional generator is added, whose available capacity has mean $\bar{\mu}$ and variance $\bar{\sigma}^2$. If the central limit theorem is applicable both before and after the new generation is added, then the surplus in the new system follows the $N(\mu+\bar{\mu}, \sigma^2+\bar{\sigma}^2)$ distribution The capacity value of the new generation, δd, may be found by solving

$$z = \frac{-\mu}{\sigma} = \frac{\delta d - \mu - \bar{\mu}}{\sqrt{\sigma^2 + \bar{\sigma}^2}}, \tag{4}$$

where if Z follows the standard Normal distribution with mean 0 and SD 1, the LOLP is $p(Z < z)$. Hence, linearising in $\bar{\sigma}^2/\sigma^2$,

$$\delta d = \bar{\mu} + z\left(\sqrt{\sigma^2 + \bar{\sigma}^2} - \sigma\right) \simeq \bar{\mu} + \frac{z\bar{\sigma}^2}{2\sigma}. \tag{5}$$

This shows that, if the properties of the original and new generation are held fixed, then the capacity value of the new generation increases as the initial risk, represented by z, increases (or alternatively as the demand mean increases).

Also, if the standard deviation of the demand distribution is increased, then σ increases; provided that the LOLP is below 50%, so z is negative, this is sufficient to imply that the capacity credit then increases towards the mean availability μ of the additional generation.

In less mathematical terms, if the new generation were perfectly reliable, then its capacity value would be equal to its mean available capacity (which in this case is the rated capacity). However, if the new generation is not perfectly reliable, then adding it increases the width of the distribution for available capacity. As a result, in order to keep the LOLP the same, the demand should be increased by less than the new generation's mean available capacity. This is illustrated in Fig. 7.

B. Higher Risk Equals Higher Capacity Credit

The result in (5) is derived assuming that a Normal approximation may be used for the existing conventional generation,

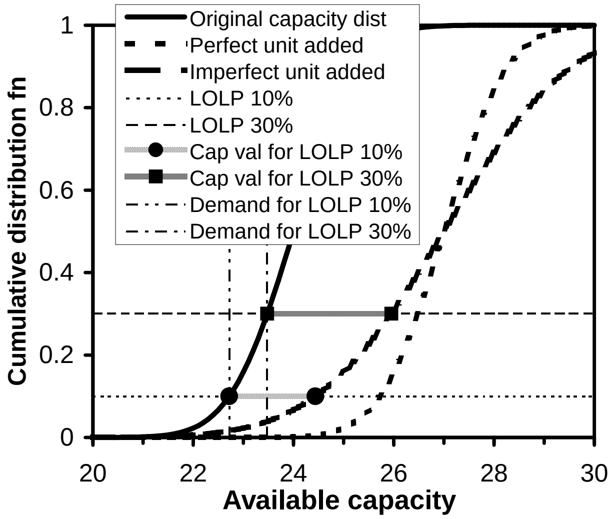

Fig. 7. Demonstration of how higher initial risk results in a higher capacity credit for new generation. The initial probability distribution for available conventional capacity is the solid black curve. If a completely reliable unit of capacity 3 is added (blue curve) then demand may be increased by 3 without increasing the LOLP. If an imperfect unit is added (red curve) so that the mean of the distribution increases by 3, but the standard deviation increases from 1 to 2, then the increase in demand keeping LOLP constant is less than 3; the capacity value of the new generation is then higher if the LOLP level is higher (cyan and magenta lines).

and that the distribution remains Normal once the additional generation is included. The Normal approximation will be reasonable provided that:

- The Central Limit Theorem (CLT) may be used for the generation availability distribution in the initial system. The CLT implies that the sum of a large number of independent random variables is approximately Normally distributed, and would require the following conditions:
  - the number of units in the initial system is large
  - none of the units dominates the sum
  - the effects of limiting station available capacities are not great
- The LOLP is not too low; the Normal approximation gradually worsens further out in the distribution tails.
- The capacity of the additional generation is not too great. The Normal approximation will still be reasonable for small wind capacities, but for higher penetrations the wind availability distribution will dominate the sum of unit capacities, and hence the CLT conditions would cease to be valid.

This explains qualitatively the results seen in the previous section (the installed wind capacities are in fact too high for a quantitative explanation):

- If the capacity of wind generation increases, then $\bar{\sigma}$ increases, and hence the capacity credit decreases.
- If the uncertainty in demand increases, then σ increases, and the capacity credit increases towards the load factor.
- When reserve is taken into consideration, the demand increases, z becomes less negative, and the capacity credit again increases towards the mean load factor.

This discussion assumes that the LOLP is less than 50%, and hence that z is negative. With regard to the last of these three points, the increased reserve requirement at high wind penetrations does actually cause a slight decrease in the capacity credit, but this is dominated by the increase in capacity credit when reserve is considered at all. In practice, due to the shape of the distribution for available wind capacity, it is relatively unusual for the additional reserve requirement to be high even at high wind penetrations.

C. Importance of Application

1) Year-Round Calculations: A number of authors (e.g. [9]) have suggested that it is best to perform a year-round risk calculation, with capacity credit being defined in terms of Loss Of Load Expectation. The time series for load and historic wind load factor can then be used to generate a time series for ([residual demand] = [demand] - [available wind]), which must be supplied by conventional generation. The clear benefit is that this uses all available information on the correlation between load and wind availability, without any technical complication.

2) GB Context: While this may be the case, the appropriate risk calculation depends on the application of capacity credit. For the GB network planning standard (which is explicitly defined at winter peak), it is appropriate to use a peak risk calculation irrespective of whether a year-round one would be more realistic in an absolute sense. The Winter Outlook (see Section II-C) presently looks at winter peak, but as there is no explicit operational risk standard it would be appropriate to use a full-winter calculation if that gives a truer picture of the real risk.

3) Modelling Planned Outages: One complication of year-round risk calculations lies in the modelling of planned outages. At the times on highest demand, in GB most generating companies try to make available as much capacity as possible; hence unit availability is a function of forced outages, which are to a good approximation independent. In a year-round calculation, it is not simple even to model just a forecast planned outage schedule. If planned outages are then modelled by a fixed schedule, the system risk in spring and autumn will be overstated significantly; in reality, there is an option of flexing maintenance schedules when margins are tight. A reasonable alternative might be to ignore planned outages entirely, and assume that the conventional plant availability distribution is the same in all hours of the year. Provided that demands during the maintenance season are far enough below peak, this would in practice be equivalent to assuming that times of high demand in winter dominate the risk.

4) Operational, and Planning Timescales: On an operational timescale, demand uncertainty is driven largely by weather. On longer timescales, there is additional uncertainty in available margins arising from imperfect estimates of underlying demand trends. This was taken into account in the CEGB planning model by increasing the width of the demand distibution (Section II-C). As capacity credits arise from risk-based calculations, it may be appropriate to add an additional demand uncertainty for capacity credit calculations which are applied to system planning.

VI. Conclusions

This paper has provided a survey of the background to capacity credits, including the context in Great Britain, followed by an example GB annual peak capacity credit calculation. Within this calculation, a number of different demand models were used, illustrating that results for capacity credit can depend strongly on the detail of the underlying risk calculation. Much of this variation can be explained by an analytical calculation, which assumes that the distributions for available capacity are Normal.

The title of the paper poses the question 'how does one perform a realistic capacity credit calculation?' In our opinion, the answer is to look carefully at the proposed use of the capacity credit value, including questions such as

- is the application defined in terms of annual peak, or is it year round?
- should additional uncertainty in demand be modelled, due to uncertain future trends on a planning timescale?

The nature of the application will determine the correct underlying risk calculation, and hence will affect the calculated value of capacity credit; while some approaches may in principle give a higher degree of realism than others, this is of little relevance if the methodology does not match the proposed application.

When comparing the results of different studies, it is also necessary to look carefully at the detailed methodologies used. Different methodologies can result in substantially different 'headline figures' for capacity credit on the same system.

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